2/1/01

Economic Analysis
High Pressure Turbine
Dense Pack Modification

Approximately two years ago, Alstom came to Intermountain and presented information on a proposed renovation of the high pr ure turbines. GE has subsequently also contacted us regarding the same modification.

The proposed modification involves changing the existing double-flow hp nozzle box to a single flow design. By doing this they are able to add stages to the hp turbine and increase hp section efficiency. Both Alstom and GE claim to have data from installed units showing an increase in turbine efficiency (decrease in flow to achieve the same output) of at least 2.0%.

The modification will be a performance contract including pre- and post-installation testing on the hp turbine section for contract validation. The following economic analysis is provided for both performance benefits and increased generation capacity.

Economic assumptions:

1- Economic life:	20 years (PV of Annuity Factor 11.2)
2- Hours of operation/year:	7884 (8760hrs/yr)(0.9capacity factor)
3- Cost of money:	6.35%
4- Cost of generation:	$42,000/ unit hour ($48.00/MW hr)
5- Avoided cost of maintenance during 2002 outage:	$708,000
6- Avoided cost of lost generation to rehab the hp nozzle:	$1,944,000 (3 days of estimated 10 required)
7- Environmental cost of SCR addition:	$85,000,000/unit
8- Modifications to balance of plant at maximum flow:	$6,000,000/unit
9- High pressure turbine section retrofit:	$4,700,000/unit

<u>Additional Generation Capacity at Existing Steam Flow</u>:

Additional potential revenue

(20MW)($48.00/MW hr)(7884 hrs/yr) = $7,568,640

Payback: <u>$2,048,000</u> (Item 9 - Items 5&6) / $7,568,640 = 0.27 years

Cost/ Benefit Ratio: (7,568,640)(11.2)/(2,048,000) = 41.4

<u>Additional Generation Capacity at Maximum Steam Flow</u> (including environmental costs):

Additional potential revenue

(50MW)($48.00/MW hr)(7884 hrs/yr) = $18,921,600

Payback: <u>$95,700,000</u> (Items 7+8+9 - Items 5&6) / $18,921,600 = 5.06 years

Cost/ Benefit Ratio: ($18,921,600)(11.2)/(95,700,000) = 2.21

<u>Performance Improvement at 875MW</u>:

Fuel Savings

(2.25%)(6.3MMlb/hr steam flow)(916 BTU/lb)(1/.88 boiler eff.)
($1.51/MMBTU)(7884hrs/yr) = $1,756,546 ($2,873,165 @ 1500 BTU/Lb)

Payback: <u>$2,048,000</u> / $1,756,546 = 1.16 years

Cost/Benefit Ratio: ($1,756,546 X 11.2)/(2,048,000) = 9.60

IP7_040319

HP TURBINE RETROFIT		
Bid Award Evaluation		
Item	GEII	Alstom
Requested Unit 2 2002 Outage Start Date	March 29, 2002 One month setback	No Change Requested
Guaranteed Delivery Date for Unit 2 HP	April 1, 2002	March 1, 2002
Guaranteed HP Section Efficiency	92.1%	92.4%
Guaranteed Section Wheel Power Output	293.480 MW	293.6 MW
Unit 1 HP Section - Base Bid	$4,100,141	$4,000,000
Unit 2 HP Section - Base Bid	$4,100,141	$5,050,000
Field Engineering Services - Unit 1	$539,676	Included in base bid
Field Engineering Services - Unit 2	$501,751	Included in base bid
Alignment Services - Unit 1	$40,100	$45,000
Alignment Services - Unit 2	$38,500	$45,000
Freight - Unit 1	$25,000	Included in base bid
Freight - Unit 2	$25,000	Included in base bid
IPSC Cost for Unit 1 HP Disasssembly in 2001	0	$100,000
HP Performance - Bid Evaluation Credit	($14,800)	($40,000)
HP Output - Bid Evaluation Credit	($50,000)	($80,000)
OEM Labor - Unit 1 (Not Included in **Total Cost**)	1,337,993	$1,260,000
OEM Labor - Unit 2 (Not Included in **Total Cost**)	1,269,154	$1,210,000
Total Cost Unit 1 and Unit 2	Price for 42.3 day outage schedule (IPSC Labor) $9,305,509	Price for 30 day outage schedule (IPSC Labor) $9,120,000
	Price for 32 day outage schedule (OEM Labor) $11,977,456	Price for 30 day outage schedule (OEM Labor) $11,590,000

IP7_040320

IGS Production and Availability History

rev 8/24/2000

Fiscal Year End Comparisons

Year		87-88	88-89	89-90	90-91	91-92	92-93	93-94	94-95	95-96	96-97	97-98	98-99	99-00	Average
Gross Generation	GWH	12,291	10,978	13,410	11,406	12,062	12,680	12,901	11,318	10,386	13,365	13,635	13,956	13,858	12,366
Net Generation	GWH	11,639	10,396	12,724	10,770	11,408	11,999	12,215	10,674	9,786	12,681	12,928	13,235	13,147	11,705
Adjusted Coal Burn*	Ktons	4,826	4,175	5,080	4,372	4,615	4,837	4,883	4,322	3,976	5,112	5,187	5,296	5,235	4,723
Adj Net Station Heat Rate^	Btu/kwhr	9,898	9,647	9,616	9,682	9,637	9,566	9,551	9,611	9,623	9,500	9,493	9,489	9,506	9,609
Availability Factor	%	89.47	80.15	95.12	92.58	91.45	93.23	92.08	92.48	87.91	93.55	94.76	94.09	93.3	91.41
Equivalent Availability Factor	%	89.32	80.02	94.99	92.51	90.24	92.97	91.78	92.04	87.30	93.42	94.64	93.93	92.40	91.10
Forced Outage Rate	%	2.33	1.16	0.58	0.66	0.33	0.29	0.09	0.21	0.19	0.64	0.12	0.68	0.87	0.61
Equiv Forced Outage Rate	%	2.48	1.32	0.72	0.75	1.63	0.56	0.42	0.67	0.87	0.78	0.24	0.72	0.97	0.93
Equiv Unplanned Outage Rate	%	2.79	2.68	1.11	1.63	2.46	0.62	0.63	0.71	0.97	1.37	0.68	1.07	0.99	1.39
Adj Net Capacity Factor**	%	82.81	74.17	90.78	76.84	81.17	85.61	87.15	76.15	69.63	90.48	92.24	94.43	93.54	83.46
Adj Net Output Factor**	%	92.56	92.54	95.62	83.63	88.76	91.84	94.85	82.40	79.24	96.74	97.35	100.44	100.26	91.33
IPSC Annual Expenditures***	$K	42,375	44,725	44,198	47,754	46,616	44,623	48,455	49,224	48,953	53,281	48,007	47,861	48,092	47,173
IPSC O&M Costs	mils/kwhr	3.641	4.302	3.474	4.434	4.086	3.719	3.967	4.612	5.002	4.202	3.713	3.616	3.658	4.030

NOTES: *Adjusted Coal Inventory applies annual coal pile inventory corrections back over multiple years.

** Net capacity factor and net output factors are calculated using a common reference of 800 MW net (since uprated load in 7/1/95 & 10/1/96).

*** IPSC O&M Budget includes fuel oil, A's & B's, & revenue from fly ash

IGS Uprate Project Coordination

Task Name	Projected Cost	2000	2001	2002	2003	2004
Unit 2 Projects	**$10,850,000.00**	**01/02/2001**				**04/01/2004**
HP Turbine Retrofit	$4,800,000.00	01/15/2001		04/01/2002		
Cooling Tower Performance Upgrade	$2,000,000.00	02/01/2001				04/01/2004
Boiler Safety Valve Addition	$250,000.00	03/01/2001		04/26/2002		
Generator Cooling Enhancements	$100,000.00	04/02/2001		04/01/2002		
Isophase Cooling Enhancements	$100,000.00	04/02/2001		04/01/2002		
Large Motor Bus Loading Equalization	$150,000.00	04/02/2001		04/01/2002		
ID Fan Suction Duct Evaluation	$150,000.00	04/02/2001		04/01/2002		
Boiler Feed Pump Performance Upgrad	$150,000.00	01/02/2001		04/01/2002		
Main Step-up Transformer Cooling	$100,000.00	03/01/2001		04/01/2002		
Burner Replacement	$2,000,000.00	03/01/2001		04/01/2002		
Scrubber Wall Ring	$600,000.00	05/01/2001			04/01/2003	
Generator SCW O2 Monitoring	$100,000.00	04/02/2001		04/01/2002		
HP Heater Drain Line Mods	$100,000.00	04/02/2001		04/01/2002		
Boiler Modifications	$250,000.00	04/02/2001			04/01/2003	
Unit 1 Projects	**$10,850,000.00**	**01/02/2001**			**04/01/2003**	
HP Turbine Retrofit	$4,800,000.00	01/15/2001			04/01/2003	
Cooling Tower Performance Upgrade	$2,000,000.00	02/01/2001			04/01/2003	
Boiler Safety Valve Addition	$250,000.00	03/01/2001			04/01/2003	
Generator Cooling Enhancements	$100,000.00	04/02/2001		03/01/2002		
Isophase Cooling Enhancements	$100,000.00	04/02/2001		03/01/2002		
Large Motor Bus Loading Equalization	$150,000.00	04/02/2001		03/01/2002		
ID Fan Suction Duct Evaluation	$150,000.00	04/02/2001		03/01/2002		
Boiler Feed Pump Performance Upgrad	$150,000.00	01/02/2001			04/01/2003	
Main Step-up Transformer Cooling	$100,000.00	03/01/2001		03/01/2002		
Burner Replacement	$2,000,000.00	03/01/2001			04/01/2003	
Scrubber Wall Ring	$600,000.00	05/01/2001			04/01/2003	
Generator SCW O2 Monitoring	$100,000.00	04/02/2001		03/01/2002		
HP Heater Drain Line Mods	$100,000.00	04/02/2001		03/01/2002		
Boiler Modifications	$250,000.00	04/02/2001			04/01/2003	

Milestone △ Summary
Fixed Delay - - - - Slack

HP Turbine Dense Pack Modifications
Operating Options and Economic and Environmental Analysis

		Unit Operation			Economics				Environmental			
Option	**Description**	**Station Max Gross Load**	**Station Net Heat Rate (BTU/KWH)**	**Station Fuel Consumption (Tons/Year)**	**Total Capital Cost**	**Benefit Per Year**	**Payback Period (Years)**	**Benefit/Cost Ratio**	**NOx Emissions per Year (Tons)**	**SO2 Emissions per Year (Tons)**	**Environmental Assessment**	**Comments**
	Current Operation	1750 MW	9500	5,268,249	NA	NA	NA	NA	26109	2984	Current Emissions limits are 0.5 lbs/MBTU of NOx and 0.15 Lbs/MBTU of SO2. Both on rolling 30 day average basis.	Current NOx emissions rate is 0.42 lbs/MBTU and SO2 is 0.048 lbs/MBTU
1	Maintain the same historical maximum load with improved heat rate.	⇔ Same	⇩ -214	⇩ -118,536	$9,400,000	$4,267,282	0.96	11.67	⇩ -587	⇩ -67	Operating in this manner should not trigger a New Source Review (NSR) or Prevention of Significant Deterioration (PSD) review. Variations from year to year would have to be explained.	There should be no change in NOx and SO2 emissions rate. Total tons per year reductions are from decreased coal burn.
2	Maintain the same historical steam flow and increase turbine/generator output. (Note 6)	⇧ 40 MW	⇩ -214	⇔ Same	$9,600,000	$15,137,280	0.28	39.46	⇔ Same	⇔ Same	Since the NOx and SO2 emissions should not change, increasing load should not mandate a NSR or PSD review. May be difficult to prove as it varies from year to year naturally.	There should be no change in NOx and SO2 emissions rate.
3	Install additional plant improvements to increase boiler and other systems capacity. Install moderate NOx reduction equipment (Note 7).	⇧ 100 MW	⇩ -214	⇧ 310,224	$36,400,000	$35,784,705	0.87	12.89	⇩ -6362	⇩ -680	Permitting with moderate NOx control should not be difficult. Current laws would require 0.46 LBS/MBTU limit in the future. Plans for more aggressive reduction (IE: SCR's) should not be made at this time.	Assumes NOx emissions will lower to 0.3 Lbs/MBTU and SO2 emissions will lower to 0.035 Lbs/MBTU (See Note 5)

Item	General Assumptions	
1	Present Value Annuity Factor (P/A, 6.35 %, 20 years):	11.2
2	Hours of equivalent operation/year (8760X 0.9 Cap. Factor):	7884
3	Cost of Fuel ($/Ton):	$36
4	Cost of replacement energy ($/MWH)	$48
5	Avoided maintenance cost for the station (Note 1):	$5,304,000
6	High pressure turbine section retrofit:	$9,400,000
7	Cost of additional plant improvements (Note 2):	$12,000,000
8	Cost of moderate NOx control equipment (SNCR):	$15,000,000
9	Operating cost per year for SNCR (Note 4):	$2,058,495
10	Coal (BTU/LB)	11,800
11	Urea (SNCR Reagent) Utilization per Ton NOx removed (Tons)	1
12	Cost of Urea per Ton (Note 3)	$300

Analysis for Option 1	
Turbine Efficiency Increase (guaranteed by supplier) =	2.25%
Boiler Heat Input Reduction = Proportional to Turbine Efficiency Increase =	2.25%
Net Heat Rate Reduction = 2.25%(9500 BTU/KWH) =BTU/KWH	214
Reduced Fuel = (Heat Rate Reduction)(Station Net Load)(Equiv.Hrs)/(Coal BTU/Lb)(2000 Lbs/Ton) = (Tons)	118,536
Benefit per Year = (Reduced Fuel)(Cost of Fuel) = $	$4,267,282
Payback Period = (Capital Costs - Avoided Costs) /Benefit per Year = Years	0.96
Benefit to Cost Ratio = (Benefit per Year)(PV Annuity Factor)/(Capital Costs - Avoided Costs) =	11.67

Analysis for Option 2	
Benefit per Year = (Increased Generation)(Equiv. Hrs.) (Cost of Replacement Energy) = $	$15,137,280
Payback Period = (Capital Costs - Avoided Costs) /Benefit per Year = Years	0.28
Benefit to Cost Ratio = (Benefit per Year)(PV Annuity Factor)/(Capital Costs - Avoided Costs) =	39.46

Analysis for Option 3	
Benefit per Year = (Increased Generation)(Equiv. Hrs.) (Cost of Replacement Energy) - Operating Cost/Year = $	$35,784,705
Payback Period = (Capital Costs - Avoided Costs) /Benefit per Year = Years	0.87
Benefit to Cost Ratio = (Benefit per Year)(PV Annuity Factor)/(Capital Costs-Avoided Costs) =	12.89
Increased Fuel = (Decreased Heat Rate)(Increased Net Load)(Equiv.Hrs)/(Coal BTU/Lb)(2000 Lbs/Ton) = (Tons)	310,224

Notes

Note 1 - Avoided maintenance cost equals the normal overhaul cost for the turbine HP section plus the avoided outage extension of 3 days to refurbish the HP nozzle block.

Note 2 - Cost of additional plant improvements are the projects necessary to increase the capacity of all other plant systems to handle the increased load. This includes the cooling towers, main transformer, generator cooling and other systems.

Note 3 - Cost of Urea is based on $0.75 per gallon for a 50% liquid solution.

Note 4 - Operating cost for SNCR includes 1% of the capital cost per year for Maintenance.

Note 5 - SO2 emissions will decrease by installation of a device to increase scrubber removal efficiency. The device eliminates the "sneakage" of flue gas around the module walls thus improving removal efficiency.

Note 6 - Capital cost includes an extra $200,000 for minor modifications to main transformer and isophase duct to handle increased load.

Note 7 - For this economic analysis, moderate NOx reduction technology is assumed to be Selective Non-Catalytic Reduction (SNCR) because it is well proven. Other technologies such as ultra-low NOx burners will be evaluated before the final decision is made.

Actuals To Future Actual

HP Turbine Dense Pack Modifications
Operating Options and Economic and Environmental Analysis

		Unit Operation			Economics				Environmental			
Option	Description	Station Max Gross Load	Station Net Heat Rate (BTU/KWH)	Station Fuel Consumption (TONS/YEAR)	Total Capital Cost	Benefit Per Year	Payback Period (Years)	Benefit/Cost Ratio	Nox Emissions per Year	SO2 Emissions per Year	Environmental Assesment	Comments
	Current Operation	1750 MW	9500	7885 BTU/KWH 5,268,249	NA	NA	NA	NA	3312#/HR 26109	2984	Current Emissions limits are 0.5 lbs/MBTU of NOx and 0.15 Lbs/MBTU of SO2. Both or rolling 30 day average basis.	Current NOx emissions rate is 0.42 lbs/MBTU and SO2 is 0.048 lbs/MBTU
1	Maintain the same historical maximum load with improved heat rate.	Same	-214	-118,536	$9,400,000	$4,267,282	0.96	11.67	-587	-67	Operating in this manner should not trigger a New Source Review (NSR) or Prevention of Significant Deterioration (PSD) review. CAVEAT	Assumes no change in NOx and SO2 emissions rate.
2	Maintain the same historical steam flow and increase turbine/generator output	40 MW	-214	Same	$9,400,000	$15,137,280	0.27	41.39	Same	Same	CAVEAT - Permit Limit Since Nox and SO2 emissions are unchanged, increasing the load should not mandate a NSR or PSD review.	Assumes no change in NOx and SO2 emissions rate.
3	Install additional plant improvements to increase boiler and other systems capacity. No new NOx control equipment	100 MW	-214	7884 7096 310,224	8319 BTU/HR $21,400,000	$37,843,200	0.43	26.33	4282 1241 2854	-680	If we agree to lower our current Nox emissions limit to 0.47 Lbs/MBTU, we might be able to get this approved as a "synthetic minor" change.	Assumes NOx emissions rate increases to 0.44 lbs/MBTU. SO2 emissions will lower to 0.035 Lbs/MBTU
4	Install additional plant improvements to increase boiler and other systems capacity. Install moderate NOx reduction equipment (ie: SNCR).	100 MW	-214	310,224	$65,000,000	$35,784,705	0.87	12.89	-6362	-680	If some decrease in Nox emissions is required, this might be the least costly alternative. There is a strong possibility that this would be "best available control technology" which would get us beyond 2007.	NOx emissions will lower to 0.3 Lbs/MBTU and SO2 emissions will lower to 0.035 Lbs/MBTU
5	Install additional plant improvements to increase boiler and other systems capacity.. Install aggresive NOx reduction equipment (ie: SCR)	100 MW	-214	310,224	$191,400,000	$32,639,250	1.49	7.54	-16236	-680	SCR's should only be installed if the currently proposed national limit of 0.15 lbs/MBTU by 2007 is actually placed into law by the EPA.	NOx emissions will lower to 0.15 Lbs/MBTU and SO2 emissions will lower to 0.035 Lbs/MBTU

@ 0.50 @ 7885 3943. 0.034 Glass 0.477 @ 8349 of what heat input 3674#/ .8963

Item	General Assumptions	
1	Present Value Annuity Factor (P/A, 6.35 %, 20 years):	11.2
2	Hours of equivalent operation/year (8760X 0.9 Cap. Factor):	7884
3	Cost of Fuel ($/Ton):	$36
4	Cost of replacement energy ($/MWH)	$48
5	Avoided maintenance cost for the station (Note 1):	$5,304,000
6	High pressure turbine section retrofit:	$9,400,000
7	Cost of additional plant improvements (Note 2):	$12,000,000
8	Cost of moderate NOx control equipment:	$15,000,000
9	Cost of aggressive NOx control equipment:	$170,000,000
10	Operating cost per year for SNCR:	$2,058,495
11	Operating cost per year for SCR:	$5,203,950
12	Coal BTU/LB	11,800
13	Urea Utilization per Ton NOx removed (Tons)	1
14	Ammonia Utilization per Ton of NOx removed (Tons)	0.37
15	Cost of Urea per Ton	$300
16	Cost of Ammonia per Ton	$300

Analysis for Option 1	
Turbine Efficiency Increase (guaranteed by supplier) =	2.25%
Boiler Heat Input Reduction = Proportional to Turbine Efficiency Increase =	2.25%
Net Heat Rate Reduction = 2.25%(9500 BTU/KWH) =BTU/KWH	214
Reduced Fuel = (Heat Rate Reduction)(Station Net Load)(Equiv.Hrs)/(Coal BTU/Lb)(2000 Lbs/Ton) = (Tons)	118,536
Benefit per Year = (Reduced Fuel)(Cost of Fuel) = $	$4,267,282
Payback Period = (Capital Costs - Avoided Costs) /Benefit per Year = Years	0.96
Benefit to Cost Ratio = (Benefit per Year)(PV Annuity Factor)/(Capital Costs - Avoided Costs) =	11.67

Analysis for Option 3	
Benefit per Year = (Increased Generation)(Equiv. Hrs.) (Cost of Replacement Energy) = $	$37,843,200
Payback Period = (Capital Costs - Avoided Costs) /Benefit per Year = Years	0.43
Benefit to Cost Ratio = (Benefit per Year)(PV Annuity Factor)/(Capital Costs - Avoided Costs) =	26.33
Increased Fuel = (Decreased Heat Rate)(Increaed Net Load)(Equiv.Hrs)/(Coal BTU/Lb)(2000 Lbs/Ton) = (Tons)	310,224

Analysis for Option 2	
Benefit per Year = (Increased Generation)(Equiv. Hrs.) (Cost of Replacement Energy) = $	$15,137,280
Payback Period = (Capital Costs - Avoided Costs) /Benefit per Year = Years	0.27
Benefit to Cost Ratio = (Benefit per Year)(PV Annuity Factor)/(Capital Costs - Avoided Costs) =	41.39

Analysis for Option 4	
Benefit per Year = (Increased Generation)(Equiv. Hrs.) (Cost of Replacement Energy) - Operating Cost/Year = $	$35,784,705
Payback Period = (Capital Costs - Avoided Costs) /Benefit per Year = Years	0.87
Benefit to Cost Ratio = (Benefit per Year)(PV Annuity Factor)/(Capital Costs-Avoided Costs) =	12.89

Analysis for Option 5 (See Note 3)	
Benefit per Year = (Increased Generation)(Equiv. Hrs.) (Cost of Replacement Energy) - Operating Cost = $	$32,639,250
Payback Period = (Capital Costs + Interest for NOx Control- Avoided Costs) /Benefit per Year = Years	1.49
Benefit to Cost Ratio = (Benefit per Year)(PV Annuity Factor)/(Capital Cost for Upgrade + Interest for NOx Control - Avoided Costs) =	7.54

Note 1 - Avoided maintenance cost equals the normal overhaul cost for the turbine HP section plus the avoided outage extension of 3 days to refurbish the HP nozzle block.

Note 2 - Cost of additional plant improvements is the projects necessary to increase the capacity of all other plant systems to handle the increased load. This includes the cooling towers, main transfomer, generator cooling and other systems.

Note 3 - Since this modification would only be done if SCR's are required by 2007, only the interest for completing the project 3 years earlier is included in the economic analysis of the option.

Note 4 - Cost of Urea is based on $0.75 per gallon for a 50% liquid solution. Cost of ammonia is for anhydrous at $0.15/lb (Current price for ammonia used for water treatment at IGS).

Note 5 - Operating cost for SNCR includes 1% of the capital cost per year for Maintenance. The Operating cost for SCR includes 2% of the capital cost due to anticipated frequent replacement of catalyst panels.

Note 6 - SO2 emissions will decrease by installation of a device to increase scrubber removal efficiency. The device eliminates the "sneakage" of flue gas around the module walls thus improving removal efficiency.

02/07/2001

IP7_040324